BEFORE THE

PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2019-224-E
DOCKET NO. 2019-225-E

In the Matter of: South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC	)))))))))	**DIRECT TESTIMONY OF NICK WINTERMANTEL ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION OF EXPERT WITNESS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Nick Wintermantel, and my business address is 3000 Riverchase Galleria, Hoover, Alabama.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am a Principal Consultant and Partner at Astrapé Consulting ("Astrapé"). Astrapé is a consulting firm that provides expertise in resource planning and resource adequacy to utilities across the United States and internationally.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I graduated summa cum laude with a Bachelor of Science degree in Mechanical Engineering from the University of Alabama in 2003. I also obtained a Master's degree in Business Administration from the University of Alabama at Birmingham in 2007.

Q. PLEASE DESCRIBE YOUR CONSULTING BACKGROUND AND EXPERIENCE.

A. I have worked in the utility industry for 20 years. I started at Southern Company where I worked in various roles within Southern Power, the competitive arm, and on the retail side within Southern Company Services. In my various roles, I was responsible for performing production cost simulations, financial modeling on wholesale power contracts, general integrated resource planning, and asset management. In 2009, I joined Astrapé as a Principal Consultant and have been responsible for resource adequacy, resource planning, and renewable integration studies across the U.S. and internationally.

Q. PLEASE SUMMARIZE YOUR TESTIMONY FOR THE COMMISSION.

A. My testimony introduces and summarizes the 2020 Resource Adequacy Study that Astrapé recently conducted on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP," and together with DEC, "the Companies" or "Duke"). While Astrapé conducted a separate study for each utility (as shown in DEC Exhibit 2 and DEP Exhibit 2, described herein), for ease of reference, my testimony refers to the two studies collectively as the "Resource Adequacy Study." I also introduce and summarize the Storage Effective Load Carrying Capability ("ELCC") Study that Astrapé recently conducted for the Companies.

Q. ARE YOU INCLUDING ANY EXHIBITS WITH YOUR DIRECT TESTIMONY?

A. Yes. I am including four exhibits with my direct testimony which are described below:

- **Wintermantel DEC/DEP Exhibit 1** is a copy of my curriculum vitae.
- **Wintermantel DEC Exhibit 2** is the 2020 Resource Adequacy Study[1] that Astrapé performed for DEC ("DEC Resource Adequacy Study").
- **Wintermantel DEP Exhibit 2** is the 2020 Resource Adequacy Study that Astrapé performed for DEP[2] ("DEP Resource Adequacy Study").
- **Wintermantel DEC/DEP Exhibit 3** is the ELCC Study prepared by Astrapé for Duke.

[1] The Confidential Appendix to the DEC Resource Adequacy Study was filed under seal on September 1, 2020, with the filing of the DEC Integrated Resource Plan and granted confidential protection by Commission Order No. 2020-616 and is incorporated herein by reference.

[2] The Confidential Appendix to the DEP Resource Adequacy Study was filed under seal on September 1, 2020, with the filing of the DEP Integrated Resource Plan and granted confidential protection by Commission Order No. 2020-617 and is incorporated herein by reference.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes. I testified before the Commission in the Companies' 2019 avoided cost proceedings in Docket Nos. 2019-185-E and 2019-186-E.

Q. BEFORE ADDRESSING YOUR SPECIFIC WORK FOR THE COMPANIES, PLEASE PROVIDE AN OVERVIEW OF YOUR EXPERTISE PERFORMING RESOURCE ADEQUACY AND PLANNING STUDIES.

A. Since joining Astrapé Consulting in 2009, I have managed target reserve margin studies; capacity value studies of wind, solar, storage, and demand response resources; analyzed generation resource selection decisions; as well as managed ancillary service studies assessing cost impacts of integrating renewables. These studies have been performed for utilities and system operators across the U.S. and internationally, principally using Astrapé's Strategic Energy & Risk Valuation Model ("SERVM"). I have developed particular expertise conducting reserve margin and capacity value studies for utilities and other entities across the country that have significant renewable penetration similar to the Companies. Over the last few years, I have worked with our Astrapé team to develop a modeling framework within SERVM to evaluate the capacity value of storage.

Q. CAN YOU PLEASE EXPAND ON ASTRAPÉ CONSULTING'S WORK IN THE UTILITY INDUSTRY?

A. Yes. Astrapé owns and is the exclusive licensor of the SERVM model. SERVM is used by utilities, system operators, and regulators to perform resource adequacy and planning studies. In the southeast alone, Astrapé has managed SERVM licenses or performed studies for utilities including Duke Energy Corporation, the North Carolina Electric Membership Corporation, Tennessee Valley Authority, Southern Company, Entergy, Central Louisiana Electric Co-op or CLECO, Georgia System Operations Corporation, Santee Cooper, and Louisville Gas & Electric. Outside of the southeast, Astrapé has used SERVM to perform resource adequacy and/or capacity value studies for other utilities and for large independent operators such as Electric Reliability Council of Texas ("ERCOT"), the Southwest Power Pool ("SPP"), the Midwest Independent System Operator ("MISO") and Alberta Electric System Operator ("AESO").

Q. HAVE YOU PERFORMED CONSULTING SERVICES FOR DUKE BEFORE?

A. Yes. In addition to the studies that are the subject of my testimony, my team also performed reserve margin studies for both DEC and DEP in 2012 and 2016. Additionally, in 2018, my team performed a Solar Capacity Value Study in parallel with a Solar Ancillary Service Study.

II. DEC/DEP RESOURCE ADEQUACY STUDY

Q. PLEASE DESCRIBE YOUR WORK FOR THE COMPANIES THAT IS THE SUBJECT OF YOUR TESTIMONY AS IT RELATES TO THE DEC/DEP RESOURCE ADEQUACY STUDY.

A. Astrapé was retained by the Companies in late 2019 to perform the 2020 Resource Adequacy Study which determines the minimum reserve margin the Companies should plan for in their respective IRPs. I was integrally involved in this work throughout much of 2020 and was primarily responsible for the modeling and development of the

Resource Adequacy Study. Astrapé completed the study for the Companies in the summer of 2020.

Q. PLEASE DESCRIBE GENERALLY THE 2020 RESOURCE ADEQUACY STUDY THAT ASTRAPÉ PERFORMED FOR DEC AND DEP.

A. This study was performed by Astrapé at the request of DEC and DEP as an update to the resource adequacy studies performed in 2016. The primary purpose of this study is to provide Duke system planners with information on physical system reliability and system costs that could be expected with various reserve margin planning targets.

Q. WHAT IS MEANT BY THE TERM "PHYSICAL RELIABILITY?"

A. Physical reliability refers to the frequency of firm load shed events. A firm load shed event, simply put, means an instance where the utility must reduce load on the system by turning off power to customers due to not having enough generation resources to serve load.

Q. HOW DOES THE RESOURCE ADEQUACY STUDY CALCULATE PHYSICAL RELIABILITY?

A. Physical reliability is calculated using Loss of Load Expectation or "LOLE." LOLE is the expected number of days in a year when the utility will not have enough resources to meet its load.

Q. WHAT IS THE LOLE STANDARD MOST COMMONLY USED IN THE INDUSTRY TO SET MINIMUM TARGET RESERVE MARGIN LEVELS?

A. The industry most commonly adheres to a "one day in 10-year" standard, which equates to LOLE of 0.1 days/year. This means the utility plans its generation resources to ensure that it will only experience one day with one or more hours of firm load shed every 10 years due to a shortage of generating capacity.

Q. WHY IS IT IMPORTANT THAT UTILITIES SET AN ADEQUATE RESERVE MARGIN?

A. Customers expect to have electricity during all times of the year but especially during extreme weather conditions such as cold winter days when resource adequacy is at risk for the Companies. In order to ensure reliability during these peak periods, the Companies each maintain a minimum reserve margin level to manage unexpected conditions including extreme weather, unexpected load growth, and significant unit forced outages. Further, as utilities continue to transition from conventional fossil fuels and rely more on intermittent and energy limited resources, it is critical to ensure reliability during this transition. The industry has relied on an LOLE of 0.1 days per year to determine an adequate reserve margin.

Q. HOW DO UTILITY PLANNERS GENERALLY CAPTURE RESOURCE ADEQUACY RISK?

A. Resource adequacy events are high impact low probability events that are seen during periods of extreme weather, periods when the load forecast is missed, or periods when significant generation is unavailable. If only normal weather, expected loads, and expected generator performance were simulated, it is expected that little to no risks would be surfaced. To understand resource adequacy risk, the full distribution of possible scenarios must be simulated at a range of reserve margins.

Q. HOW DID ASTRAPÉ CALCULATE PHYSICAL RELIABILITY AND CUSTOMER COSTS FOR VARIOUS RESERVE MARGIN LEVELS FOR THE DEC AND DEP SYSTEMS?

A. To calculate physical reliability and customer costs for the DEC and DEP systems, Astrapé utilized the SERVM reliability model to perform thousands of hourly simulations for the 2024 study year at various reserve margin levels. Each of the yearly simulations was developed through a combination of deterministic and stochastic modeling of the uncertainty of weather, economic growth, unit availability, and neighbor utility assistance. For this analysis, a combination of thirty-nine weather years were simulated with five economic load forecast error multipliers, and fifteen random generator forced outage draws totaling 2,925[3] hourly simulations for the 2024 study year at each reserve margin simulated. Each of the yearly simulation results are weighted based on their probability of occurrence to calculate LOLE and expected system costs at each reserve margin level.

Q. WERE STAKEHOLDERS INVOLVED IN REVIEWING THE INPUTS AND METHODOLOGY OF THE 2020 RESOURCE ADEQUACY STUDY?

A. Yes, stakeholders were integrally involved in reviewing and defining the Base Case assumptions and a list of planned sensitivities to be evaluated in the study. Several stakeholder meetings were held to discuss these inputs, the study methodology, and results of the study. These stakeholder meetings included representatives from the South Carolina Office of Regulatory Staff ("ORS"), the North Carolina Public Staff, and the North Carolina Attorney General's Office. Following the initial meeting with

[3] 39 weather years * 5 Load Forecast errors * 15 generator forced outage draws = 2,925 hourly simulations.

stakeholders on February 21, 2020, the parties agreed to the key assumptions and sensitivities listed in Appendix A, Table A.1 of DEC's and DEP's respective Resource Adequacy Study.

Q. IN ADDITION TO THE BASE CASE, WERE OTHER CASES OR SCENARIOS MODELED IN THE STUDY?

A. Yes, Astrapé modeled a Base Case, Island Case and Combined Case as well as multiple sensitivities in the study.

Q. PLEASE DESCRIBE THE BASE CASE AND ISLAND CASE SCENARIOS AS MODELED BY ASTRAPÉ.

A. In the Island scenario, it is assumed that DEC and DEP is each responsible for its own load and that there is no assistance from neighboring utilities. Under this scenario, DEP would require a 25.5% winter reserve margin and DEC would require a 22.5% winter reserve margin to each achieve LOLE of 0.1 days/year. The results of this scenario are shown in Table ES1 (Island Physical Reliability Results) of each study. In the Base Case scenario, it is assumed that DEC and DEP would be able to receive market assistance from neighboring utilities during capacity shortfalls. Under this scenario, DEP would require a 19.25% winter reserve margin and DEC would require a 16.0% winter reserve margin to achieve LOLE of 0.1 days/year. The results of this scenario are shown in Table ES2 (Base Case Physical Reliability Results) of each study.

Q. PLEASE EXPLAIN WHY THE COMPANIES' RESOURCE ADEQUACY RISK IS SEEN PRIMARLY IN THE WINTER.

A. The increase of solar penetration as well as the volatility of winter peak loads has shifted almost all resource adequacy risk to the winter for both DEC and DEP. Because solar capacity is coincident with peak load in the summer but provides very little capacity contribution to peak load during the winter, increased solar penetration decreases summer resource adequacy risk substantially more than winter resource adequacy risk. Similarly, volatility in winter peak loads is much greater than summer peak load volatility causing risks to be concentrated in the winter.

Q. PLEASE DESCRIBE THE DEC/DEP COMBINED CASE SCENARIO THAT ASTRAPÉ MODELED.

A. The DEC/DEP Combined Case scenario was used to see the reliability impact if DEC and DEP were able to operate as a single balancing authority. In this scenario, DEC and DEP prioritize helping each other over their external neighbors but also retain access to external market assistance. Under this scenario, DEC and DEP would require a 16.75% combined winter reserve margin to achieve LOLE of 0.1 days/year. An additional sensitivity was run in this scenario to assume a maximum import limit from external regions into the DEC/DEP utilities of 1,500 MW, which results in an increase of the reserve margin from 16.75% to 18.0%. The results of this scenario are shown in Table ES3 of each study.

Q. PLEASE DESCRIBE THE SENSITIVITIES THAT WERE SIMULATED IN THE 2020 RESOURCE ADEQUACY STUDY.

A. A range of sensitivities was simulated in the study to understand which assumptions and inputs impact study results and to address questions and requests from stakeholders. Sensitivities included both physical and economic drivers of reserve margin. The results of these sensitivities can be found in Section VII and VIII of each study.

Q. PLEASE DESCRIBE ASTRAPÉ'S RECOMMENDED WINTER RESERVE MARGIN FOR THE COMPANIES.

A. Based on the physical reliability results of the Island Case, Base Case, Combined Case, and additional sensitivities of both studies, Astrapé recommends that the Companies continue to maintain a minimum 17% winter reserve margin for IRP purposes.

Q. HOW DID THE COST OF VARIOUS RESERVE MARGINS FACTOR INTO YOUR ANALYSIS?

A. While Astrapé believes physical reliability metrics should be the primary factor in setting reserve margins, Astrapé also analyzed system costs across various reserve margins. The major finding was that there are relatively small differences in costs across a range of reserve margins for both Companies as shown in Figure ES1 (Base Case Risk Neutral Economic Results) and Table ES5 (Annual Customer Cost vs LOLE) of both studies. As discussed, and shown in Table ES5 of the studies, for a relatively small increase in costs above the costs associated with a risk neutral reserve margin level, customers will experience enhanced reliability and less rate volatility.

Q. PLEASE DESCRIBE WHY THE 17% MINIMUM WINTER RESERVE MARGIN IS REASONABLE.

A. Customers expect reliable electricity during extreme hot and cold weather conditions and maintaining a 17% reserve margin as a minimum target provides reasonable reliability from an LOLE perspective. Astrapé recognizes that a standalone DEC or DEP utility would require reserves of 22.5% and 25.5% respectively to meet the one day in 10-year standard but believes that a reasonable level of market assistance should be taken into account. The Base Case analysis shows DEC requires a 16.0% reserve margin and DEP requires a 19.25% reserve margin to meet the one day in 10-year standard, and the Combined Case shows a 16.75% reserve margin is required. After taking all of these results into account, a 17% reserve margin is reasonable. As discussed in the reports, a 17% minimum reserve margin does not mean that the Companies will never be forced to shed firm load during extreme conditions. Recent historical years have shown periods where operating reserves were close to being exhausted even with higher than 17% planning reserve margins. But if not for non-firm external assistance which this study considers, firm load would have been shed.

III. STORAGE ELCC STUDY

Q. PLEASE DESCRIBE YOUR WORK FOR THE COMPANIES THAT IS THE SUBJECT OF YOUR TESTIMONY AS IT RELATES TO THE STORAGE ELCC STUDY.

A. Astrapé was retained by the Companies in early 2020 to perform the Storage ELCC Study. I was integrally involved in this work and was primarily responsible for the modeling and development of the Storage ELCC Study. Astrapé completed the Study for the Companies in the summer of 2020.

Q. PLEASE DESCRIBE THE PURPOSE OF THE STORAGE EFFECTIVE LOAD CARRYING CAPABILITY STUDY THAT ASTRAPÉ CONDUCTED.

A. The Storage ELCC Study was conducted to analyze the capacity value of battery technology within the DEC and DEP systems.

Q. WHAT IS MEANT BY THE TERM "CAPACITY VALUE" AND HOW IS IT UNIQUE TO BATTERY STORAGE TECHNOLOGY?

A. The "capacity value" of a resource is the reliability contribution of the generating resource. Said otherwise, the capacity value represents the battery's ability to reliably provide capacity when it is needed. Because battery systems have limited energy storage capability and must be recharged, either from the grid or a dedicated generation resource, the capacity value of a battery is different from a resource such as a gas-fired turbine, which can be called upon in any hour to produce energy (notwithstanding a unit outage).

Q. PLEASE DESCRIBE THE APPROACH USED BY ASTRAPÉ TO CONDUCT THE STORAGE ELCC STUDY.

A. Similar to the Resource Adequacy Study discussed earlier, the system is targeted at 0.1 LOLE to represent a reliable generating system. Next, a storage resource is added to the system. When capacity, such as the storage resource, is added to the system, LOLE decreases, meaning the system is more reliable. Then, load is added to the system (which is modeled as a negative generator) until the reliability of the system is returned back to the 0.1 LOLE standard. The amount of load added to the system divided by the battery capacity results in the capacity value of the storage resource, also known as the effective load carrying capability of the resource. This process is used to evaluate every battery configuration studied.

Q. WHAT TYPES OF BATTERY OPERATING MODES WERE ANALYZED IN THE STUDY?

A. Astrapé modeled battery resources in three operating modes using SERVM. I describe these as (1) Preserve Reliability Mode (2) Economic Arbitrage Mode and (3) Fixed Dispatch Mode based on a set rate schedule.

Q. WHAT ARE THE DIFFERENCES GENERALLY BETWEEN THE PRESERVE RELIABILITY, ECONOMIC ARBITRAGE, AND FIXED DISPATCH OPERATION MODES?

A. Under the Preserve Reliability Mode, the battery is fully controlled by the utility and is only used to provide energy during reliability events. While this method would provide the most capacity value, it provides little to no economic value and is not how batteries are typically expected to be run on the system. For this reason, this mode is largely an academic exercise that provides a theoretical maximum capacity value but is not directly useful for planning purposes.

Under the Fixed Dispatch Mode, the utility has no control over the battery's operations and the owner of the battery discharges the battery (i.e., injects energy onto the utility's system) based on when the energy is the most valuable from an economic standpoint. This mode is only assumed for third-party owned batteries that are paid pursuant to the avoided cost rates set by the Commission under the Public Utility Regulatory Policies Act (PURPA).

Under the Economic Arbitrage Mode, the battery is fully controlled by the utility, but instead of being used only during reliability events, the utility discharges the battery to maximize the economic value of the battery. This means that the battery is charged at times when system energy costs are low and is discharged during peak net load conditions when system energy costs are generally high and loss of load events are most likely to occur. Economic Arbitrage Mode best represents how a battery would be dispatched on the DEC and DEP systems.

Q. PLEASE DESCRIBE GENERALLY THE RESULTS OF THE STORAGE ELCC STUDY.

A. The results of the Storage ELCC Study are shown in Tables 5 and 6 for stand-alone batteries and Tables 9 and 10 for batteries paired with solar. Tables 5 and 6 show the average capacity value (for stand-alone batteries) using the three modes of battery operation (Preserve Reliability Mode, Economic Arbitrage Mode, and Fixed Dispatch Mode) across a number of battery penetrations and storage durations. Specifically, we evaluated batteries of various duration (2-hour, 4-hour, and 6-hour) with varying amounts of battery capacity assumed on the system, at two different solar penetration levels. Tables 9 (and 10 similarly show the average capacity value for batteries paired with solar using the Economic Arbitrage mode and the Fixed Dispatch mode, with varying assumptions around the duration of the battery, the solar penetration on the system, the maximum project capacity added to the system, and the battery capacity as a percentage of the associated solar.

Q. PLEASE DESCRIBE THE HIGH-LEVEL CONCLUSIONS ASTRAPÉ REACHED BASED ON THE STORAGE ELCC STUDY RESULTS.

A. The results of the Storage ELCC Study estimate significant capacity value for 4-hour and 6-hour storage for both Companies to assist in offsetting winter reliability risks, whereas 2-hour storage provided less capacity value, as expected. In general, standalone battery capacity value increases with more solar on the system because additional solar narrows the net load peak period allowing the battery to more easily reduce reliability events. Also, the capacity value reduces as more battery storage is added to the system. This is because as battery penetration increases, the system's net load peaks are flattened. This lowers the capacity value of incremental energy storage as battery systems must discharge for longer periods to serve the wider net load peak. In DEP, the first 800 MW of 4-hour storage result in an average capacity value of 94% - 97% depending on the level of solar penetration assumed. By the time the system reaches 2,400 MW, the average capacity value decreases to 78% - 80%. Similarly, in DEC, the first 400 MW of 4-hour storage results in an average capacity value of 92% -100%. By the time DEC reaches 1,600 MW of 4-hour storage, it is estimated to have an average capacity value of 80% - 86%. The study reveals significant capacity value in scenarios where the utility had dispatch rights over the storage compared to the owner discharging or charging based only on an economic rate schedule. The combined solar plus storage projects, including those with a battery to solar ratio of up to 50%, showed capacity values commensurate with the battery size. While this study does include some level of operator uncertainty due to day-ahead dispatch of storage, there are potentially additional operational constraints of storage technology that were not explored in this study. For example, there were no charging/discharging constraints, ramping constraints, daily cycle constraints, or degradation assumed in this Study. As the Companies and industry gain experience with large-scale deployment of storage, these estimates should be revisited.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. It does.